STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 41736

IN THE MATTER OF THE INVESTIGATION ON THE COMMISSION'S OWN MOTION INTO ANY AND ALL MATTERS AFFECTING THE ADEQUACY AND RELIABILITY OF ELECTRIC SERVICE TO INDIANA RETAIL CUSTOMERS

FINAL REPORT

July 31, 2001

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Cause No. 41736: Final Report

Introduction:

The investigation was begun by an IURC order on May 10, 2000. The order explained that the investigation was begun due to many factors that had been occurring in the electric industry. These factors included changes in the wholesale electric power market stemming from the Energy Policy Act of 1992 and various orders of the Federal Energy Regulatory Commission; situations in Indiana in the summers of 1998 and 1999 when capacity was strained and voluntary conservation requests were issued; actions of the Environmental Protection Agency to further reduce pollutants that greatly affect Indiana's generating plants; and the prospect that changes for the industry will continue to be rapid and be influenced from a variety of sources including environmental, regulatory, and legislative events. Consequently, the IURC commenced the investigation into any and all matters affecting the adequacy and reliability of electric service to Indiana retail customers.

All electric generation, distribution, and transmission utilities within the state of Indiana and under the jurisdiction of the Commission were named as Respondents to the investigation. A list of pertinent issues was attached to that order as Exhibit "A". A pre-hearing conference was held on May 30, 2000, to elicit the views of the parties and to further develop the scope of the proceeding. It was determined that a series of seven technical conferences (or "sessions") would be held. The IURC staff developed a list of questions for each session, and parties filed written comments before each session took place.

The IURC employed an outside facilitator to help frame and direct the discussions that took place at the technical conferences. The outside facilitator was Scott Hempling[1], a noted industry attorney and consultant. Once the written comments were received, the IURC staff and the facilitator worked together to develop clarifying questions and areas of further inquiry to be addressed at the actual session. To encourage frank discussion by the participants, the oral sessions were not conducted on the record and a court reporter was not present. For the first time in such a proceeding, the commission utilized its website to post information about the sessions and the written comments from the

[1] Scott Hempling, Attorney-at-Law holds a J.D. magna cum laude from Georgetown University Law Center, where he was a recipient of an American Jurisprudence award for Constitutional Law; and a B.A. cum laude in Economics and Political Science from Yale University, where he was a recipient of a Continental Grain Fellowship and Patterson Award. Scott Hempling advises clients on regulation and competition in the electric industry, with an emphasis on market structure, mergers and acquisitions, corporate restructuring, ratemaking diversification and State-federal jurisdictional issues. He is a frequent witness before Congressional committees and lecturer at industry conferences. His clients include State commissions, independent power producers, municipal power systems, residential consumers and public interest organizations.

parties.[2] One of the goals of the investigation was to increase public awareness of the complexities of the issues surrounding reliability of electricity, and posting the questions and comments on the internet helped to accomplish this goal. Seven technical conferences were conducted. The first took place on June 30, 2000, and the last one on November 20, 2000. The titles and dates of the sessions were:

- Session 1: **Alternatives to Traditional Generation Resources:** June 30, 2000
- Session 2: **Recent Environmental Protection Agency (EPA) Actions:** July 20, 2000
- Session 3: **Multi-State Utility Operations:** August 14, 2000
- Session 4: **Regional Reliability Issues:** September 7, 2000
- Session 5: **Generation Planning and Reserves:** October 5, 2000
- Session 6: **Non-Utility Owned Generation:** October 30, 2000
- Session 7: **Service Quality Issues:** November 20, 2000

[2] The information is posted at: http://www.state.in.us/iurc/energy/indexrelpro.html

<u>Session 1:</u>
Alternatives to Traditional Generation Resources
Meeting Date: June 30, 2000

Objective: The objective of this session was to examine alternatives to building new generation facilities to maintain or enhance system reliability. Alternatives discussed included technologies such as distributed generation, "green power" resources and customer load management strategies such as conservation programs and curtailable or interruptible options.

Written comments for Session 1 were submitted by: American Electric Power (AEP, Indiana Michigan Power Company), Citizens Action Coalition, Hoosier Energy, IBEW Local 1395, Indiana Statewide Association of Rural Electric Cooperatives, Indianapolis Power & Light, Regulatory Assistance Project, Northern Indiana Public Service Company (NIPSCO), Office of Utility Consumer Counselor, PSI Energy, Inc. (PSI, Cinergy), Southern Indiana Gas & Electric Company, and Wabash Valley Power Association.

Summary of Written Comments for Session 1:

1. What role is there for "distributed generation"?

The consensus of responses concludes that there is a limited, yet useful role for distributed generation (DG) currently, and that this role could grow substantially in the future. Today the economics of central station generation is still better than those for DG. Whether that changes in the future depends on further developments for both DG and central generating technologies, and that of course is unknown. There are other reasons why a customer might install DG. For example, a customer may place a very high value on reliability and so having on-site generation able to meet some or all of their load during utility outages is very attractive. Another example is for customers who pay a demand charge based on their peak load. In this case, the ability of DG to shave peak load is again very attractive. Distributed generation can also be used as an alternative to distribution capacity expansion or to a line extension. Not all of these uses are appropriate in all circumstances, while some may be more valuable to a customer and others to the utility responsible for serving load.

2. Are Indiana utilities exploring the efficient and economic usefulness of distributed generation? Are there barriers to utilities using distributed generation?

Indiana utilities or their affiliates are exploring distributed generation technologies. Some are testing DG units in the field, and some have also invested in companies that are involved in distributed generation. In September 1999, Cinergy Technologies Inc. (an affiliate of PSI), and the Crane Division, Naval Surface Warfare Center, commissioned a collaborative project to evaluate proton exchange membrane fuel cell power plants for military and commercial use. AEP has build a test facility to determine the electrical characteristics of DG and has already tested photovoltaics and microturbine devices. An affiliate of NIPSCO has been working on a project to evaluate DG in conjunction with Walgreen Drug stores.

Respondents identified several potential barriers to DG. These included lack of customer knowledge about DG systems, the Certificate of Need law in Indiana that, according to some, may prohibit utilities from owning any new generating capacity without first obtaining permission from the IURC, uncertainty surrounding the restructuring process across the country, uncertainty as to how well the new DG technology will actually function in real-world applications, lack of uniform interconnection and utility performance standards, safety, reliability, high initial cost, lost revenues for the utility, and that during delays in siting and placement a project's economics can shift from economic to uneconomic. It should also be noted the price of natural gas, the fuel for many DG applications, is crucial to the economics. DG applications economical at $2 or $3 mmbtu gas may not be profitable for prices above that level.

3. What incentives, broadly defined, provide for the further development and use of environmentally friendly resource options?

The government could help by providing subsidies, tax credits, or low interest loans to encourage increased research and development of environmentally friendly resources; by encouraging pilot programs for utilities and consumers; and with utility ratemaking incentives and performance-based ratemaking. The government could also participate through the placement of distributed generation resources at government facilities or buy green power to encourage a more robust market for it.

Actions that utilities could take include implementing green power purchasing options, net metering tariffs, and provide local distribution credits where appropriate.

A third area identified by some parties that would encourage environmentally friendly resources is the reduction of technical barriers to installation, the reduction of interconnection barriers created by utility practices, and the reduction of barriers created by ratemaking practices.

4. How should the term "environmentally friendly resource" be defined? Should it include "green power," clean-coal technologies, conservation, load management, or some types of generation technology?

Responses indicated that there is not a simple answer to this question. The responses ranged from including existing, "over-scrubbed" coal-fired generation to limiting the definition to non-combustion renewable technologies excluding nuclear power. One respondent suggested that the term "environmentally friendly" should encompass a broad range of sources of technologies including green power (wind, solar, hydro, geo-thermal), brown power (landfill methane, coalbed methane, waste coal), clean coal technology and demand-side management.

5. What environmentally friendly resource options have promise in this region of the country?

Although several respondents argue that solar and wind power hold little promise in Indiana, others refute that and say that solar (photovoltaic systems) and wind power may have a valuable role to play. Other options identified include: landfill and coal-bed methane, low head hydro, clean coal technology, conservation and load management to lessen the spike of daily summer demand peaks, biomass, municipal waste, and tire-derived fuels.

6. How can electric utility companies and government agencies best reflect environmental externalities and uncertainties when evaluating the comparative costs of resource options?

This question evoked a wide range of responses with no clear-cut consensus answer. At one end of responses were two parties who believed that environmental externalities are already accounted for in the various environmental regulations and so utilities and governmental agencies need only follow these regulations. At least one party argued that the uncertainty of proposed and future EPA regulations was damaging to the resource planning process. Another respondent argued that non-coal energy sources face their own "externalities", such as radioactive waste management for nuclear and land use costs for wind. Finally, one party argued that the IURC and utilities should recognize that clean resources are significantly underutilized in today's industry because the societal and environmental benefits are not fully accounted for, and that aggressive public policies should promote clean electricity resources. The respondent argued for implementing a public benefits charge (generally a consumer-funded mechanism collected through utility rates) that would be large enough to implement all cost-effective energy efficiency resources.

7. What type of ratemaking alternatives should be considered to encourage electric utilities and their customers to give greater consideration to environmentally friendly resources?

The Citizens Action Coalition (CAC) recommended the following policies: 1) energy efficiency should be promoted through a public benefits charge and a third-party administrator[3]; 2) renewable resources should be promoted through a Renewables Portfolio Standard (RPS)[4]; and 3) distributed generation resources should be promoted through a variety of measures to remove the technical, institutional and regulatory barriers that they face today. Others mentioned these ideas in various ways as well, and also promoted the idea that utilities should simply offer a green or renewable power option to customers at the cost of those options so that consumers have the ability to exercise their preferences for these sources. Other issues cited were that uncertainty with

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[3] A third-party administrator means an independent entity that is funded through a public benefits charge levied on customers and oversees the specific conservation and renewable programs that are implemented.
[4] A Renewables Portfolio Standard (RPS) is a policy that obligates each retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources.

respect to regulation and legislative rulemaking is a barrier to investment in all types of resources; the usefulness of tax incentives to encourage investment; and net metering provisions that allow customers with wind or solar power to offset a portion of their energy bill.

8. In a broader sense, what type of alternative regulations could enhance reliability?

Some alternative regulations listed include having customer choice in Indiana, and having service quality and reliability standards with carefully designed specific performance criteria. It was also noted that care must be taken to ensure that regulatory and ratemaking policies do not have unintended consequences, such as discouraging operations and maintenance (O&M) expenditures and capital investment.

9. What methods or options could be used to encourage end-use customers to conserve electricity?

Methods of conservation can be grouped into two main areas: those aimed at changing customers' behavior and those aimed at raising the efficiency of appliances and houses for everyone. If customers face a more market-oriented price signal in the form of real-time pricing or time-of-use rates[5], they will reduce their energy use during episodes of high prices. An indirect way of reducing consumers' usage is for the utility to install direct load control devices on certain equipment such as air conditioners or swimming pool heaters. During times of peak usage, the utility can switch off these appliances on a rotating basis to reduce peak load. In exchange, the customers receive a credit on their electric bill. Another method identified is to use taxation to artificially raise the price of power and thus apply pressure on consumers to reduce their energy consumption.

Energy use for everyone can be reduced through the continued use of federal and state building codes and appliance standards. These methods should be promoted through trade groups, public interest groups, and energy suppliers and service companies.

"Traditional" demand-side management or energy efficiency programs drew comments from the CAC. It argued for allowing a third-party administrator to implement energy efficiency programs and to allow customers to share a portion of savings from their conservation efforts.

[5] Real-Time Pricing is the instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer. Time-of-Use (TOU) rates are the pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on peak, mid peak, off peak), and by seasons of the year (summer and winter). Real time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices, which may fluctuate many times a day and are weather sensitive, rather than varying with a fixed schedule.

10. What methods or options could be used to manage customers' load, especially during peak periods?

Options that were not covered in the answers to question 9 included off-peak energy storage options; buy back programs offered by utilities such as interruptible rates or call options contracts[6]; and allowing for demand-side bidding in the wholesale electricity market.

Summary of Session 1 Discussions:

The day started with a summary of the IURC Integrated Resource Planning (IRP) rules currently in place for electric utilities. The present IRP rules (170 IAC 4-7, sections 1-9) became effective on August 31, 1995, and were implemented to assist the IURC in analyzing the long range needs for expansion of facilities for the generation of electricity and to plan for meeting the future requirements of electricity as required by IC 8-1-8.5 (the Utility Powerplant Construction Law).

The summary of the IRP process was followed by a discussion of how the reliability and capacity factors of renewable power should be taken into account in the IRP process. The consideration of additional benefits of alternative generation projects was debated. These benefits include the added jobs created and low emission rates of the technologies. It was generally agreed that the Certificate of Public Convenience and Necessity (CPCN) statute is broadly worded and allows for review and evaluation of these types of issues.

The benefits of distributed generation to utility planning and operations were covered, with emphasis on the areas of alternatives to distribution capacity expansion, line losses, alternatives to line extensions, dispatchability to shave the peak, the applicability to specific customer groups, and the capacity potential of distributed generation (DG). In Indiana, utilities are in the beginning stages of both evaluating DG as a resource and in actual experience with customers. There is a learning process within the companies and in interacting with customers who are installing DG projects on their premises. As an example, after one utility processed the interconnection with a wind power project the first time, it was approached by a second customer about the same type of project, and at that point it was better able to respond to the second customer's questions. There was some discussion of having the utilities share any standard letters or other material regarding interconnection policies for their customers. This could protect the utility against accusations that they are not responsive to alternative power projects. This discussion also debated whether the IURC should issue a rulemaking to standardize interconnection rules for the state. It was noted that the Institute of Electrical and

[6] An interruptible rate is a lower rate offered by a utility to a customer that allows the utility to interrupt electric service. A call option contract allows the utility to call upon a specified amount of power or load from a customer when the wholesale price reaches a certain price (the strike price).

Electronic Engineers (IEEE) were developing interconnection standards, with the issuance about two years away.[7]

Demand-side load management options were also discussed. First, a discussion about price-induced customer behavior took place. Utilities stated that customers tended to be very responsive to price signals if they have a reason and the ability to respond to the signal. It was also stated that larger customers have the understanding to modify their electricity usage or make economic decisions not to, and metering technology is still too expensive to install on a widespread basis for small load customers. Second, direct load control (such as air conditioner and water heater) was discussed, with some utilities sharing opinions as to why they have implemented it and how it has worked, and others explaining why they have not implemented it yet and why they are evaluating it for the future.

Issues for Further IURC Consideration:

The IURC should focus on reducing or eliminating barriers to DG in the following four areas: 1) the CPCN process; 2) DG interconnection standards; 3) buy-back rates; and 4) stand-by rates. The commission should encourage innovative rates to be developed and implemented. The IURC staff should review current rate designs, the efficiency of these rates, and how rate designs could change given restructured wholesale markets. The IURC staff should also analyze how rate design might affect alternative types of generation and general DSM programs.

Under IC 8-1-8.5 (Utility Powerplant Construction), prior to constructing, purchasing, or leasing any facility to generate electricity for its customers, a utility must first obtain a certificate of public convenience and necessity from the commission. Since there is no lower limit or threshold amount specified in this law, all projects, no matter how small, are subject to the CPCN process. This process can require many hours of work and a good deal of time before a certificate is issued by the commission. These factors may be an impediment to utilities that otherwise might be leaning toward installing a DG project on their system. Therefore, the commission and, more importantly, the state legislature, may want to consider enacting some other type of proceeding for smaller generating projects. Establishing a new process and a threshold amount of generation would have to be carefully thought out so that loopholes would not exist. For example, if the limit were 10 MW, a utility could file for ten projects of 8 MW each under the new process, in essence adding 80 MW of generation on their system.

The argument against establishing a threshold or limit for smaller projects is that every addition by a utility should be the least-cost option in the integrated resource planning process, and so should be subject to the CPCN process. Still, if Indiana would like to encourage new, innovative generating technologies, even if they may not be the least cost

[7] It now appears that IEEE P1547, Draft Standard for Interconnecting Distributed Resources with Electric Power Systems, is on target to be published in late 2001.

option, establishing a threshold may be a worthwhile idea. There are many types of DG units that are quite small, so even if the limit were one, two or five MW, it would probably encourage some additional DG projects. A limit per utility per year could be established so that utilities could gain some experience with DG technologies. If the technology proves to be cost effective, then utilities could file for larger numbers of DG units under the CPCN statute.

A second area worthy of IURC attention is interconnection standards for DG, green, or other generation resources that non-utility parties may want to build and connect to the electric grid. There are interconnection standards for qualifying facilities in place now that were enacted due to PURPA (Public Utilities Regulatory Policies Act of 1978)[8]. Whether these guidelines are still adequate or need to be revised for projects of this era would be part of any effort by the commission to establish rules for DG and net metering for Indiana. The commission may instead wish to monitor the national effort at establishing interconnection standards, and adopt some variation of those in the future.

Another alternative to traditional generation is changing demand-side behavior, especially in times of peak electricity demand. This issue was brought up often throughout this investigation. The current situation is that, in general, at peak usage the cost of producing or purchasing power is very high, but customers do not face this price and therefore have no incentive to change their demand for electricity. Participants often cited this point as one of the factors that has contributed to the problems in California. If consumers were to face some type of price signal, peak demand would be reduced, which would lessen the need for construction of new peaking plants. The commission should encourage any steps by utilities or others to implement programs that give consumers more accurate information about their electricity usage.

Indiana electric utilities have implemented many different types of these peak-shaving programs, some for the first time in 2000 or 2001. The IURC should continue to gather and share as much information as it can on the successes and failures of these programs, especially if the weather in 2001 is hot enough so that swings in wholesale market prices and other aspects cause these programs to be actually called upon.

[8] Indiana Utility Regulatory Commission, 170 IAC Rule 4.1 Cogeneration and Alternate Energy Production Facilities.

<u>Session 2:</u>
Recent Environmental Protection Agency (EPA) Actions
Meeting Date: July 20, 2000

Objective: This session examined the plan and strategies for maintaining system reliability assuming the utilities will be required to meet new EPA standards. The Commission was particularly interested in how the utilities may be coordinating among themselves to assure reliability. Also, the Commission was interested in learning if and how non-utility owned generation might be used to help maintain reliability.

Written comments for session 2 were submitted by: American Electric Power, Hoosier Energy, IBEW Local 1395, Indiana State AFL-CIO, Indianapolis Power & Light Company, Natural Resources Defense Council/Indiana Clean Energy Campaign (Citizens Action Coalition of Indiana, Hoosier Environmental Council, Save the Valley, Valley Watch, Inc.), Northern Indiana Public Service Company, Office of Utility Consumer Counselor, PSI Energy, Inc. (Cinergy), Southern Indiana Gas & Electric Company,

Summary of Written Responses for Session 2:

1. How might the EPA lawsuit asserting that maintenance activities trigger new source standards affect generation adequacy and reliability?

The utilities argued that if EPA was successful at changing the rules under which utilities maintain equipment, the EPA might either force the retirement of otherwise economically viable plants or promote poor maintenance practices. In both cases, utilities argued that generation adequacy and reliability would be adversely affected. Two other deleterious effects were mentioned: first, during the time of pollution control installation, the increased number of units offline create a potential reliability problem; second, after all the equipment is online, there could be a decline in the amount of available generation due to capacity derates at each unit, which would reduce the overall reserve margin.

In its comments, the Natural Resources Defense Council (NRDC) stated that there is no significant impact or risk to the system reliability due to the EPA lawsuit. The NRDC stated that the EPA has had a long-standing policy under the Clean Air Act of evaluating individual projects to determine whether that project meets the definition of “routine maintenance” for purposes of New Source Review. Because of this continuing EPA policy that utilities have long been aware of, the NRDC believes that the EPA enforcement action cannot be reasonably interpreted to threaten system reliability from forced outages due to delayed routine maintenance or from shutdown of units subject to enforcement action.

2. How might the proposed EPA 8-hour NOX standards affect reliability?

Several respondents pointed out that the proposed 8-hour NOX standards are currently in abeyance due to court actions. The standards, originally proposed by EPA in 1997, were remanded back to EPA by the U.S. Court of Appeals in the District of Columbia to correct deficiencies in the rulemaking. The EPA appealed this decision to the U.S. Supreme Court. There are currently no direct emission limits imposed on the utility industry by this rule. The EPA would have to undertake a new rulemaking to implement emission limits that relate to an 8-hour ozone standard. The main rule discussed in this session was the NOX SIP Call[9] rule, which the EPA promulgated in October 1998. This rule addresses the regional transport of ozone and requires a reduction of NOX emissions by utility boilers of approximately 65%.

3. How might the petitions by some states to the EPA regarding adverse environmental affects allegedly caused by utility emissions in other states impact generation adequacy and service reliability in Indiana and this region of the country?

The Section 126 petitions by the states were generally seen as having the same effect on reliability as the NOX SIP regulations. It was noted that EPA intended the SIP Call requirements to be consistent with those of the Section 126 petitions, and therefore the potential impacts of these requirements are not cumulative.

4. Assuming that more stringent environmental standards are implemented, how does the utility plan to meet these standards, especially given the limited time frame available for implementation?

Utilities generally stated that they were working on their compliance plans while waiting for the final outcome of the NOX rules. The plans will entail some combination of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technology, overfire air, operational combustion optimizing/tuning, banking and trading of NOX credits, and possibly some fuel switches to natural gas. Utilities stated they would attempt to take advantage of already scheduled unit outages (in the lower load seasons of the spring and fall), but some outages would necessarily have to be extended. These outage extensions lead to reliability concerns if the longer outages coincide with unseasonably warm weather that causes high load conditions across the state or region.

5. What is the type of compliance planned? What length of time will construction take? Will it require down time for existing capacity and for what period of time?

[9] SIP stands for State Implementation Plan. Each state must file a plan with the U.S. EPA to implement the proposed federal regulation? in this case, additional restrictions on the formation of nitrogen oxides (NOX) by large industrial and utility boilers. The plan that the state develops to meet the proposed regulation is known as a state implementation plan, or SIP.

Will the final compliance strategy result in derates for current capacity? What will the new unit availability be?

The types of equipment have been listed above in response to question #4. The estimates of the length of time for construction of an SCR unit ranged from 12 to 30 months. Connecting the SCR equipment to the generation unit will require additional outage time beyond that for normal maintenance. One utility noted that each SCR requires two generation unit outages of three and six weeks beyond normal maintenance, while another thought the additional outage time would be in the two to six week range. Opinion was not uniform on whether the equipment results in a derate. Most thought no derates would result, while one respondent mentioned a 2 MW magnitude and another thought there would be derates but they could not be quantified beforehand. There was uniform opinion that unit availability with the new equipment online should be the same as before.

6. How does new non-utility owned plant capacity affect any reliability risk posed by EPA's actions? How can this be taken into account in assessing reliability?

Most respondents stated that non-utility owned generation should help to ease reliability concerns, but that it was impossible to quantify the impact today. However, it was noted that it is premature to assume that this new capacity will provide some assurance of reduction in reliability risk because there is no mechanism in place to transfer any responsibility for reliability to the non-utility generator. In other words, a non-utility generator does not have the same obligation to serve requirements that a franchised utility does. Another uncertainty is how the transmission grid will function as the result of the addition of these non-utility units.

7. Given possible future EPA actions, what are the long-term prospects for the continued operation of coal-fired generating plants? What are the long-term prospects for new coal-fired generating plants?

Most respondents believed that coal-fired generation, both existing and potential new plants, would continue to play a significant role in electricity generation, even though continuing EPA regulations are forcing the cost of it ever higher. An Energy Information Administration (EIA) Short-Term Energy Outlook from March 2000 was quoted: "Coal remains by far the least expensive fossil fuel for electric utilities. Coal prices are expected to decline through 2000 even after costs associated with the Clean Air Act Amendments (CAAA) are included. Continued increases in mining productivity have kept coal supply costs on a gradually declining trend for many years. The same cannot be said of natural gas." Another respondent quoted an analyst as saying that if all of the existing fleet of coal units were forced to meet new source standards for SO2 and NOX, 94% of them would still be economical to operate.

Summary of Session 2 Discussions:

Janet McCabe, Assistant Commissioner, Office of Air Quality—Indiana Department of Environmental Management, spoke at the beginning of this session in order to give everyone an overview and update of the various EPA pollution control initiatives.

Following the IDEM presentation, each of the utilities was asked to describe the status of their NOX reduction plan. Some utilities noted that the equipment applied was very unit specific, that there were possible catalyst poisoning issues, a learning curve to climb on dealing with large amounts of ammonia, and a concern about the availability of skilled labor to perform the installations.

Next a short debate occurred about reliability studies conducted by NERC[10] and ECAR[11]. The NERC study was performed in late 1999, and it assumed a worst-case scenario and an 18-month retrofit period. The ECAR study was based on survey responses from the utilities, and it concluded that the ECAR region would have up to 10 days during the retrofit period in which reliance on supplemental reserves from outside the region would be necessary. The study acknowledged that the actual result would depend upon the quantity of merchant plant generation constructed. The ECAR study also concluded that if the retrofit window was 42 months or longer, there was not a reliability concern, while if the window was 30 months or less, reliability would be decreased significantly. Utilities generally stood behind the studies' conclusions that stated there was a concern for reliability, while the Citizens Action Coalition pointed out flaws it saw in the studies, and believed that compliance would be possible without reliability problems. The CAC believed that the studies should have been updated to reflect more current information, including the addition of merchant plants, and the status of utilities' ongoing NOX compliance construction programs.

More details followed regarding the utilities' NOX Compliance plans. Some planned to use availability outages to perform some of the work. An availability outage is when the utility looks at the market prices for the next two weeks or so, and if prices are flat/favorable, it will go ahead and take the unit offline to perform maintenance work, or in this case pollution control equipment installation. Due to the uncertainty of the rulemaking at the time, many utilities stated that they had cancellation provisions in their contracts with pollution control equipment vendors. They also constructed their plans so that "off ramps" to SCR installations were available if conditions changed. Many were doing the most obvious and least costly equipment installations first.

Later in the day one critical issue came to the fore: that of availability of materials and skilled labor to do all of the NOX control equipment installations. Utilities were unanimous in stating that availability of labor is a serious issue, and that the wages would probably be a premium to keep these workers (such as boilermakers and ironworkers) on

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[10] *Reliability Impacts of the EPA NOX SIP Call*, North American Electric Reliability Council, February 2000, www.nerc.com.
[11] *ECAR Reliability Analysis of the EPA NOX SIP Call*, 00-GRP-63, East Central Area Reliability Coordination Agreement, January 2000, http://www.ecar.org/publications/GRP/default.htm.

the job. This potential problem also could lengthen the outage times. Worries about the availability of heavy steel and the catalyst were also stated.

The issue of coordination of outages was covered. One participant stated that early on in the process there was some talk at NERC and ECAR of coordinating outages, but there were not any concrete efforts at doing so now. A utility argued that there were antitrust concerns with sharing information about unit outages. Another utility wondered what the IURC would do with such information if it thought that too many units were going to be offline and potentially compromise reliability.

Finally, the issues of early reduction credits and NOX trading programs were discussed. It was noted that the potential for trading was much less than under Phase I of the SO2 regulations because the proposed limit for NOX emissions was very low, and the technology will not allow a unit to achieve emissions very far under the regulated rate.

Update:

Since this reliability session was held, the courts have upheld the NOX SIP Call. The court did change the deadline so that NOX control equipment will need to operate on May 31, 2004, rather than the previous deadline of May 2003. Any extension should lessen concerns about reliability. The IDEM Air Pollution Control Board finalized the rule in June of 2001.

The NOX rule will allow Indiana utilities to participate in a regional trading program for NOX emission allowances. The rule also contains a compliance supplement pool of NOX allowances that is available to utilities making early reductions or those who can demonstrate a need for an extension during 2004 and 2005. A need exists when a utility can demonstrate it cannot meet the 2004 compliance date without creating an undue risk to the electricity supply.

The Section 126 petitions which affect some of Indiana's utilities (generating plants in the eastern half of the state) are still in effect, and those deadlines are in the spring of 2003. This ruling was recently reaffirmed by the U.S. D.C. Court of Appeals. This past winter, Cinergy announced a settlement with the EPA on environmental regulations and efforts, and this settlement will satisfy the Section 126 petitions. At this time no finalized settlement has been filed with the court.

Issues for Further IURC Consideration:

The overriding concern for the IURC to emerge from this session has been the potential for reliability problems due to too many units being offline at the same time to install NOX control equipment. The IURC is examining this issue in conjunction with the State

Utility Forecasting Group at Purdue University. Additional concerns of the IURC are the availability of skilled labor and material, the cost of the equipment being installed, and the learning curve that utilities face when they begin to operate this new equipment.

The change in Presidential administration and new energy and environmental policy direction from the federal executive branch will also be of interest to the IURC. The administration has proposed a national energy policy, which it describes as a comprehensive long-term strategy that integrates energy, environmental and economic policies. These policies are likely to be reflected in proposed legislation. Any legislation based on the administration's energy plan will be in addition to numerous bills already introduced in the Congress. One such bill that has been introduced has provisions to repeal PURPA, relax diversity requirements in PUHCA, and create a new national body to oversee reliability[12]. There may also be new environmental regulations enacted by the EPA to control mercury, carbon dioxide, and other emissions. If implemented, such changes will surely have an effect on the future role of coal and gas-fired generation, and hence reliability, in Indiana.

Recent events across the nation regarding electricity prices, outages and natural gas prices show the interdependencies of America's energy service sector. Environmental stewardship is important. If environmental and market regulatory initiatives are largely uncoordinated, the results can be economically inefficient at best and create shortages at worst. Environmental regulations need to be well thought out, based on sound science, and should provide certainty for market participants for a variety of pollutants for a significant number of years. Also, the heavy dependence of Indiana and the region on coal-fired generation capacity for the foreseeable future emphasizes the need for a coordinated approach to environmental emissions control requirements to preserve and maintain reliability.

[12] National Energy Security Act of 2001, S. 388, introduced by Frank Murkowski (AK-R). The Democratic caucus is expected to introduce an energy policy bill also.

Session 3:

Multi-State Utility Operations
Meeting Date: August 14, 2000

Objective: The objective of this session was to examine how retail restructuring in other states and the competitive wholesale market affect reliability in Indiana. Participants discussed strategies or methods for maintaining electric reliability for the native load customer.

Written comments for Session 3 were submitted by: American Electric Power, Citizens Action Coalition, Indiana State AFL-CIO, Indiana Statewide/Wabash Valley Power Association, Indianapolis Power & Light Company, Office of Utility Consumer Counselor, PSI Energy Inc., and Southern Indiana Gas & Electric Company.

Summary of the Written Comments for Session 3:

1. How might a multi-state utility holding company that has traditionally operated its separate utility subsidiaries on a highly coordinated basis operate when it operates in some states that continue to have traditional regulation and other states that have retail competition?

PSI Energy explained in its response that there will necessarily be some change, but what those changes are will probably be unique to the multi-state company, since the length of time the company has been operating across state lines, the degree of highly coordinated multi-state planning and operations, and the system operating agreement are all unique to the company. PSI Energy stated that because of these reasons, there are probably no simplistic, "one size fits all" answers to these questions. The operating agreement[13] may need to be changed, though, according to a few respondents.

2. What economic incentives or disincentives are present under the circumstances described in Question 1 to maintain reliable electric service at reasonable rates to the end-use customers being served under traditional regulation?

The CAC stated that the incentive for meeting these responsibilities should continue to be the threat that utility net income can be adjusted by the Commission for failure to perform reliably and that revenue requirements can be adjusted to reflect changed asset utilization and expense patterns. Several other parties generally concurred with these ideas, citing the most basic statutory mandate—the obligation to serve at reasonable cost—as an historical and ongoing incentive.

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[13] Operating agreement here refers to the document that explains how a holding company's individual operating companies and affiliates, typically including a service company of the holding company, conduct business with each other.

3. Are the existing system operation agreements relevant or even useful anymore?

AEP stated that the existing AEP system pooling and coordination agreements continue to be relevant and useful, but that as the industry and its reliability protocols are changed, these agreements may need to be changed. The OUCC, however, shared a concern about potential harm to Indiana utilities if a multi-state utility divests its generation in a restructured state. In this case, which refers to AEP in particular, the holding company could call upon the Indiana utility's generation stock on an embedded cost basis while forcing the Indiana utility to expose itself to a higher degree of market risk through the sharing of an increased level of power purchases. The OUCC also argued that the Cinergy operating agreement seems to expose its Indiana utility to a greater degree of market risk for purchased power in this hypothetical case of generation divestiture in another state.

In restructured states without generation divestiture, the OUCC stated two concerns. First, proper accounting safeguards need to remain after restructuring in another state so that costs are not shifted between the competitive generation affiliate and the traditionally regulated utility. Second, the lack of prudence reviews in restructured states could allow a utility to shift costs of generation units between jurisdictions, which could harm Indiana ratepayers. In other words, the usefulness of operating and interconnection agreements in the past relied implicitly on the assumption of prudence reviews in all of the relevant states. The OUCC recommended that the Indiana utility's participation in its operating/interconnection agreement with its affiliates should be carefully reviewed and monitored.

4. How might the reorganization of generation operations and facilities in some states affect reliability when generation has been so closely coordinated within the holding company across multiple states?

Both the OUCC and PSI Energy stated that reliability should not be adversely affected. The OUCC believed that there may be engineering issues that arise, but saw no issues regarding technical implementation that give rise to special concerns at this time. PSI Energy noted that the deregulation of generation in neighboring states does not change the physical availability of that or any other generation. PSI argued that there is evidence that the application of market forces has resulted in both more efficient utilization of existing generation and a recent increase in the planned generation throughout the ECAR region.

AEP stated that the move towards customer choice and a competitive generation market system with hundreds of players is creating a risk for the existing bulk power transmission system by creating increased usage of the system for which it was not designed. This trend is independent of whether multi-state utilities are reorganizing their corporate structures. AEP believed that state and Federal authorities should support actions to stimulate expansion of the transmission grid.

The CAC stated that the principal concern is that capacity that has been available to support service to native load customers in Indiana may be diminished or no longer available. The CAC detailed two ways this could happen: first, that generation capacity may be withheld from the market in order to capture the highest price possible in the wholesale market or withheld for fear that an emergency on one's own system will subject a utility to spikes in market prices, and second, asymmetrical development of competitive retail electric supply across multi-state holding companies may lead to the diminution of reserve-sharing and cost-sharing mechanisms built into holding company operating agreements. If these sharing limitations are realized, Indiana electric consumers will be adversely affected through degradation of reliability, an increase in rates, or both, the CAC stated.

5. What does it mean for Indiana customers if these other states rely upon "markets" to provide the necessary investment in generation facilities to maintain an adequate level of reliability?

AEP stated that the competitive wholesale power market is attracting investment in new generation facilities at a level to insure an adequate level of reliability. PSI Energy stated that Indiana utilities will continue to meet their obligations to provide reliable electric utility service by pursuing the same cost-effective strategies to meet their retail customer loads that they have historically pursued. IPL mentioned the theoretical possibility of boom/bust cycles for the generation market and the resultant variations in reliability, but added that variations in generation investment and therefore reliability exist even under traditional regulation.

6. Even if the Indiana operations of multi-state utilities continue under the current form of regulation, are their Indiana customers, in reality, depending on the market to maintain adequate generation for reliability?

Most respondents stated the answer is "Yes" but that the situation is not different from today. Currently Indiana utilities rely upon a variety of resources to meet load, including the wholesale market. Further, most utilities have historically relied upon each other for power, as no single utility could reasonably afford to be completely self-sufficient. One utility noted that the wholesale power market has brought about a change in the environment. The power market brings with it price volatility similar to the natural gas market. Also, sellers in the market are not obligated to sell to the buyers, other than at whatever price the market bears. Another utility stated that it fully expected that utilities will construct new generating resources if the utility determines that new generation is the most cost-effective resource acquisition compared to other options. In this sense, the market will continue to have an impact on the generation resource decisions made, and the price of generation incurred, by Indiana utilities.

7. How can the prices resulting from the dynamics of the competitive wholesale market be translated to the Indiana retail customer under the current form of regulation? Does the disconnection between wholesale prices and the prices Indiana retail customers experience complicate the operation of multi-state utilities? Would

the complications be reduced/eliminated if the retail customers experienced prices that more directly reflect the wholesale price dynamic? Please explain.

Respondents did not agree that the premise of the first question was necessarily a good idea. The OUCC stated that it is not economically efficient for retail customers to be exposed to the full dynamics of the wholesale power market unless they are capable of responding to those prices in a similar time frame. IPL stated that it has been their experience that customers prefer to decrease rather than increase the variability of the price signal they receive and that an alternative to exposing all customers to price volatility would be for the utility to exercise a moderate amount of control over the underlying load demand. However, AEP stated that as the move to competition advances, if retail markets are to place a check on the price for generation, retail customers must receive more appropriate price signals from the wholesale market.

With respect to the second question, parties generally agreed that there is a disconnect between wholesale and retail prices, but this does and should not cause any more complications for the operation of a multi-state utility. This general response thus rendered the third question moot.

Summary of Session 3 Discussions:

This topic naturally engaged discussion from and about AEP and Cinergy much more so than from other Indiana electric utilities. The first topics covered were a summary of the new rules and regulations of the restructured Ohio electric industry, and how a utility operating in Ohio may handle any potential loss of customers. On January 1, 2001, Ohioans were allowed to choose their electricity supplier, and the generation of electricity was deregulated. Transmission and distribution functions continue to be regulated. This change came about from the passage of Senate Bill 3 in June 1999, which was signed into law in July 1999.

Other topics discussed were whether multi-state systems can and will be dispatched together or separately, other types of changes in operations, multi-state utility operating agreements, and the process of a utility with deregulated generation facilities transferring some of these generation assets to an Exempt Wholesale Generator (EWG). Also discussed were the risks of cost shifting between deregulated and regulated subsidiaries and how that might be monitored and policed by the IURC, ECAR obligations, transmission planning and operations, regional transmission organizations (RTOs), a possible regional regulatory body for states, and a joint federal-state regulatory board.

Issues for Further IURC Consideration:

The basic issue for further commission attention is the monitoring of the operations of multi-state utilities. The IURC should continue to further its understanding of these utilities, with particular emphasis on possible cost shifting between affiliate companies, dispatch methods of the companies' generation fleets, and the accounting issues arising from reserve sharing and energy transfers between the operating companies.

The IURC should continue to monitor, understand, and participate in the changes occurring with companies' generation and transmission assets. The commission needs to ensure that reliability will not be harmed, but rather enhanced, by a multi-state utility's membership in a regional transmission organization, or by implementing a new operating agreement for its operating companies.

In light of the retail restructuring in neighboring states, the IURC should be concerned with how these changed circumstances affect utility incentives. Operating agreements, service agreements, affiliate rules and codes of conduct need to be reviewed with consideration given to these changed incentives. Critical analyses of the operating agreements for Cinergy and AEP are the most obvious pressing tasks before the commission. Possible elimination of PUHCA means that the commission should review and develop new methods to monitor the relationship between utility subsidiaries and non-regulated affiliates. This would include a review of service and operating agreements, affiliate rules and codes of conduct. The analysis is particularly important regarding multi-state utility holding companies, but many of these same concerns apply to non-registered holding companies with increasing numbers of non-regulated affiliates.

<u>Session 4:</u>
Regional Reliability Issues
Meeting Date: September 7, 2000

Objective: The objective of this session was to discuss how the reliability of the electric system in Indiana might be maintained or improved by regional entities such as Regional Transmission Organizations or Power Exchanges. The increasingly regional operation of wholesale markets and the need for access to region-wide transmission facilities makes it necessary to find ways to address reliability from a regional perspective, the Commission is interested in discussing methods of encouraging regional solutions to reliability concerns.

Written comments for Session 4 were submitted by: American Electric Power, Citizens Action Coalition, Hoosier Energy, Indianapolis Power & Light Company, Midwest Independent Transmission System Operator, Inc., Northern Indiana Public Service Company, Office of Utility Consumer Counselor, PSI Energy, Inc., Southern Indiana Gas & Electric Company, and the Wabash Valley Power Association.

Summary of the Written Comments for Session 4:

1. Can a Regional Transmission Organization help maintain or enhance system reliability even though it may not control all transmission facilities within a regional market? Could this situation actually put system reliability at risk?

Responses to this question varied but in the main the answer was "It depends." It was recognized that, all other things equal, a larger RTO is better, but the reality of how it is setup and managed is critical. For example, SIGECO noted that "actual operating experience must be achieved before judgment can be made." A further point of some agreement was that regardless of RTO development and structure, system reliability should not be harmed or degraded, because NERC/ECAR standards and rules will continue to apply to electric control areas. There was also general agreement that one or more RTOs in the region would enhance reliability. While recognizing that "seams issues" between RTOs will always exist, RTOs should benefit reliability in that they will have a more complete knowledge of the system than the individual control area operators and therefore will be able to make better decisions regarding the operation and expansion of the transmission system.

The CAC argued that having some Hoosier electric utilities belong to one RTO and others to a second RTO would compromise reliability in Indiana. The CAC argued that the "holes and seams" issues were too great to overcome, and that federal legislation was likely necessary to solve the dilemma. Some examples of seams issues between RTOs include congestion management protocols, the reciprocal elimination of pancake transmission charges (price reciprocity), coordination of commercial practices, security coordination, market monitoring, regional planning, transmission capability calculations, curtailment procedures, and coordinated outage planning.

2. What economic incentives or disincentives are present in Regional Transmission Organizations or in the electric industry, in general, to help maintain and/or enhance transmission-related reliability?

First, several respondents noted the inherent incentive for every player in the market to keep the system reliable because during an outage, no one is making money. The rate of return on transmission assets was mentioned as a possible disincentive due to the low amount set by FERC (historically as low as 9%, recently 11.6%). Other disincentives present in an RTO structure or in the electric industry in general are that siting new transmission is difficult and expensive; jurisdiction is split between state and federal regulation, and is often unclear; and a general concern that regulatory processes will delay cost recovery.

Performance-based and incentive regulation was stated as a possible solution to encourage new transmission construction. This type of rate mechanism was discussed in FERC's Order 2000 and it would involve rewarding a transmission owner with a higher rate of return or allowing it to keep more revenue from transactions on its system if the owner performs well.

3. What economic incentives or disincentives are present in the current electric industry to motivate transmission-owning utilities to join RTOs? Should penalties be assessed against utilities that fail to join an RTO? Please explain.

An "incentive" to join an RTO has involved the use of FERC's approval authority, frequently its authority to approve electric utility mergers. The FERC has treated an electric utility's agreement to join a FERC-approved RTO as a mitigation mechanism to address market power concerns and other possible negative effects of mergers.

Several parties cited one disincentive that motivates against utilities joining an RTO is the loss of transmission revenue. Since an RTO would eliminate rate pancaking[14], utilities argue that the revenues they would receive from the RTO would not be as high as the level they currently receive in pancaked rates. Joining an RTO was also seen as costly in terms of potentially not being able to recover costs of the membership fees. The loss in control of transmission facilities was stated as another detriment to RTO membership. Other disincentives listed were the fear that only transmission owners would be in favor of implementing innovative rates among an RTO's membership; and the fear that a distribution company with a rate freeze in effect might have to absorb higher costs due to RTO membership.

Some possible incentives listed were allowing a higher return on transmission assets for utilities that join an RTO; for generators and distribution companies, access to a wider

[14] Rate pancaking occurs when a power transaction flows over several transmission systems. In the pre-RTO environment, the party selling the power must pay a fee to the owners of each transmission system.

market in which to buy and sell power. Thus, power is moved across the grid in a more cost-effective way.

The CAC stated that FERC should put great pressure on those utilities that fail to join an RTO by scrutinizing their actions, particularly any anti-competitive behavior, closer than those who are members of RTOs. The CAC noted that the advantages of an efficient, well-managed RTO are obvious, but that legislation may be needed to implement RTOs.

AEP noted that presently there are no positive incentives to join an RTO. It argued that both state and federal regulators should cooperate to insure that no transmission owner suffers trapped transition costs as a result of rate freezes during and after the RTO transition, and that any promised incentives are realized as they are earned. AEP also argued that incentives which reward all transmission owners who join RTOs are appropriate, and it argued that incentives are needed to ensure that necessary transmission construction will be funded. One commenter recommended penalties for utilities that fail to join an RTO, while four other parties were against that idea.

4. Should penalties be assessed against transmission-owning utilities or RTOs when transmission-related problems put reliability at risk? Please explain under what circumstances penalties should be assessed and what form the penalties would take.

The general response to this question is "No"; additional penalties imposed by state regulatory commissions should not be assessed because reliability requirements already exist from NERC and ECAR policies. Hence, remedies already exist should a utility intentionally or recklessly harm reliability. NERC and ECAR have recently put various financial penalty policies in place. Hoosier Energy stated its support for the ECAR filing at FERC entitled "Inadvertent Settlement Tariff." This tariff presents specific monetary penalties and remedies should an ECAR member inadvertently "lean on" the system and essentially use power produced by others to serve its own load.

5. Are initiatives on reliability requirements and possible penalties for not meeting those requirements proposed by the North American Electric Reliability Council and its regional subgroup, East Central Area Reliability Coordination Agreement (ECAR), sufficient and appropriate for maintaining the reliability of the regional transmission system?

A general theme running through several responses was that this issue will need to evolve as the market develops, and that federal legislation will probably be needed to bestow upon NERC or its successor the ability to implement penalties. PSI Energy stated that the initiatives move in the right direction, but they need to be revised in order to:

1) reduce the scope of the requested data in order to reduce the resources required to meet the data requests
2) require all market participants that might negatively impact system reliability to comply with such requirements

3) better match the severity of the penalty with the severity of the non-compliance and the impact on system reliability
4) assure that the requirements are implemented and enforced consistently between and across regions
5) ensure that any mandatory elements are truly needed for system reliability.

6. Would a Power Exchange improve the availability of power during severe conditions such as the 1999 heat wave?

All six of the Indiana electric utilities that answered this question answered it "No." They argued that a power exchange (PX) would not increase the physical amount of power that is available for sale, and that the current bilateral market already provides price discovery (some examples are: cash delivery can be found in the Wall Street Journal, active, "over the counter" brokered markets, and electronic markets such as Altrade, Bloomberg Powermatch, EnronOnline and HoustonStreet). It was also argued that Power Exchanges that focus on the short-term market do not allow producers an effective, long-term mechanism for hedging their large capital investments.

Many of the utilities also brought up the failure of the California Power Exchange, arguing that the experience underscores the point that a PX has limited capabilities, and can actually be a part of the problem of supply shortages and high prices. Dissenting from this view was the CAC. It argued that a properly constructed PX would improve the availability and lower the cost of power in a region, and, in the long-term, provide appropriate price signals to customers and potential new entrants to guide investment behavior.

7. Outside of formal entities such as RTOs and PXs, are there other ways of maintaining regional reliability of the electric system?

Governmental and regulatory actions identified included removing barriers to the siting of new transmission and generation facilities, implementing incentive-based regulation that focuses on performance and provides incentives to invest in new facilities, and promoting policies that give consumers more real-time price signals during times of peak usage. One commenter argued for a greater reliance on market forces to guide investment, while another argued that some entity needs to ensure that adequate information is available to market participants and to the public. Examples of necessary information include the status of construction of new generation facilities and any constraints on the availability of fuel supply. Finally, it was argued that Midwest RTOs must design metering standards, bidding protocols, settlement protocols, and imbalance markets conducive to active participation in wholesale markets by non-traditional resources such as "negawatt" bids by customers.

Summary of Session 4 Discussions:

The first major theme of the day was an explanation of the historical use and purpose of the transmission system, and how that use has been transformed into something different, and not planned for, today. Traditionally, the primary role of the transmission system was to deliver energy from jurisdictional generation plants to jurisdictional load, with occasional economy transactions occurring. Around fifteen years ago, another role began to dominate the system: transactions between control areas. This has made the day to day running of a control area's transmission system much more difficult. Utilities are in more of a reactive mode simply because they cannot predict the number and direction of transactions that will be flowing through their control area on any given day. Planning a transmission system is about collecting information, but this has become more difficult because of so many more players in the market today. As a result, companies are sharing more information than before, and some are becoming more proactive in terms of meeting with their own large customers to find out what their needs may be in the future. Two utilities agreed that instead of a new transmission planning mechanism, the utilities should share more information with the state public utility commissions (PUCs). Another party argued that transmission planning needs to take place at a broader, market level, and that a neutral party needs to collect and share information.

The increase in the number of TLRs (transmission loading relief requests) from 1999 to 2000 was discussed. The TLR is a NERC procedure used to mitigate potential or actual violations of the operating limits on critical transmission equipment. These procedures are an escalating series of actions to reduce the electrical flow across key portions of the transmission grid. Transmission operators are supposed to begin the TLR procedure when they notice the amount of power moving across a critical transmission facility is approaching one of its thermal limits. When this happens, transmission operators notify the security coordinator in their control area who "calls" the TLR beginning at Level 1. This first level is simply an advisory to other security coordinators that a problem has been observed. Potential or existing transactions are affected if the security coordinator escalates the TLR to level 2 or higher. Three reasons for the increase in TLRs were put forth by the participants: a change in alertness level, or simply more vigilance on the part of security coordinators in calling TLRs; more local congestion issues; and new parties finding new trading opportunities.

A long discussion on economic signals and the risks of building new transmission facilities followed. Some argued that the federally-set rate of return on transmission assets was too low to make building new lines an attractive proposition, while it was also argued that in California since deregulation, there has been an explosion in transmission projects. Those arguing that the return was too low said that some types of incentives were necessary to bring forth new construction, which was countered by the argument that a company should not receive an increment above a fair rate of return in order to motivate it to do something for the public good. One speaker summed up by stating that there is a national desire to make the whole transmission system more robust, but there are risks for individual utilities to make an investment to develop a more robust wholesale market. Another speaker stated that utilities make transmission investments when they have to, not because they choose to voluntarily.

The treatment of transmission constraints and locational marginal pricing was discussed next. One speaker first noted that RTOs in the Midwest had not yet developed a congestion management plan, which was the case with every RTO that did not originate from a tight power pool. It was asserted that what will be needed is a real-time imbalance market and the implementation of incentives to promote as many economic transactions as possible.

The next idea discussed was resource diversity issues. The idea here was that some existing and proposed imbalance rules impose penalties if the supply varies outside of a band, say +/- 1%. These types of rules thus penalize renewable resources such as wind and solar power that typically have output that varies greatly. Therefore it was argued that a solution to this problem would be needed when RTOs and other reliability rules were implemented. An example might be for a less than 10% imbalance, the generator would pay the market price for the difference. Another solution would be to have a real-time imbalance market that sets the price for any imbalances.

Some of the other topics covered briefly at the end of the day included regional transmission organizations, generation planning, whether an RTO must control all of the region's transmission facilities, gaps in regional facilities, the number of control areas, incentives to join RTOs, coordination among RTOs, the state commission role, processes for planning and approval of new facilities, and access to information.

Issues for Further IURC Consideration:

Regional reliability issues are paramount in the development and operation of RTOs. The IURC, along with several other Midwestern states, has been a strong and unwavering advocate that the region will be best served by a single RTO that has a wide geographic scope. At this time, it appears that there will be two RTOs serving the region and the state. Consequently what are known as "seams issues" take on high importance. In order for reliability to remain high, and for Indiana utilities to be able to have good access to wholesale electricity markets, the RTOs must operate as one. The IURC has been heavily involved in the RTO development process so far, and it will surely continue this level of engagement in the future.

Specific issues of concern to the IURC include the evolution or creation of a new, national reliability organization to enact rules and regulations for market participants, the authority for and ways to promote new transmission lines where necessary, and transmission congestion in Indiana and the Midwest.

<u>Session 5:</u>
Generation Planning and Reserves
Meeting Date: October 5, 2000

Objective: The objective of this session was to review the technical planning process used by the utilities and to examine the strategies used to maintain reliability standards based on the results of the planning process. Particular attention was given to how the rapidly changing electric utility industry makes the planning process more difficult and how these factors are incorporated into utility strategies for meeting customer demand and maintaining system reliability.

Comments for Session 5 were submitted by American Electric Power, Citizens Action Coalition, Hoosier Energy, Indiana Industrial Energy Consumers, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company, Office of Utility Consumer Counselor, PSI Energy, Inc., and Southern Indiana Gas & Electric Company, and Wabash Valley Power Association

Summary of the Written Comments for Session 5:

1. What are the appropriate levels of needed generating reserves?

Many respondents stated that there is no single answer to this question, and that the appropriate level of generating reserves can vary from utility to utility. For example, a utility with no interconnections might need a 30 to 40% reserve margin[15] to obtain minimal or zero generation-related service interruptions. However, a utility that has good interconnections with the transmission grid, and that can exploit its diversity with other utilities might be able to reduce its reserve margin to 10%. The factors involved in setting an appropriate reserve margin include: transmission capacity and interconnections, generation unit size, unit availability, fuel diversity, and load uncertainty. The OUCC pointed out that the State Utility Forecasting Group (SUFG) uses a 15% benchmark for assessing Indiana's statewide reserve margin, and the CAC urged the IURC to require Indiana utilities to maintain a 15% level of planning reserves.

IPL pointed out that of the key factors involved, unit availability is the most crucial, and that an ECAR report showed that a one percentage point improvement in system availability equates to a 1.1 percentage point reduction in required capacity margin[16] for ECAR. PSI Energy explained that there are other methods for determining reserve

[15] The reserve margin is the percentage difference between rated capacity and peak load divided by peak load.

[16] The capacity margin is the percentage difference between rated capacity and peak load divided by rated capacity.

margin aside from the percent generation approach. These methods are the loss-of-the-largest-generating-unit method, the loss-of-load-probability (LOLP) method, and the expected unserved energy probability (EUE) method. PSI also stated that utilities should start their analysis with the minimum Operating Reserve required by NERC and ECAR.

Two respondents, AEP Energy Company and the Indiana Industrial Energy Consumers (INDIEC) asserted that the market should be allowed to set the correct level of reserves to manage the risk of final delivery. AEP believed this method was appropriate even in the current, largely regulated environment. INDIEC stated that the market-based system, with safeguards against accumulation of undue market power and the ability to redress market power abuse, would have adequate price signals available to all market participants to determine whether additional capacity is needed. Most respondents also mentioned that utilities continue to have an obligation to serve and are required to meet that duty in the most cost-effective manner.

2. What is the adequate level of operating reserves and how might this change in the near future?

Several respondents stated that the current operating reserve margin level is set by ECAR for its member companies to be 4%, which consists of spinning and supplemental reserves. This level of 4% was reduced from the old level of 6% when ECAR implemented the Automatic Reserve Sharing (ARS) system, which requires ECAR members to lower their Daily Operating Reserve to zero in order to support each other during operating capacity emergencies. The ARS system support is intended for temporary use, and the deficient Control Area must balance its load and resources so that the interconnected system will be prepared to withstand the next contingency. Many respondents did not expect any change in the required 4% level in the near future.

3. Does the traditional planning reserve margin have any meaning beyond projecting needs a year or two out? How does the planning process reflect the increasing age of generating facilities?

Each party who responded answered the first question in the affirmative. A utility must plan its reserve margin out further than two years simply because the time to plan, permit, obtain regulatory approval, and build even a simple-cycle combustion turbine could take up to four years. Larger base load facilities could take two to three times that of a combustion turbine, so although a twenty-year planning horizon may not be appropriate any longer, ten to fifteen years may be necessary and useful.

Regarding the second question, several respondents pointed out that aging units could reduce unit availability, and thus a higher reserve margin may be required. However, others stated that the planning process captures the increasing age of generating units by regularly updating unit performance characteristics and associated operations and maintenance costs.

4. Does long-term resource planning serve a useful purpose? Should it change and, if so, how?

Reponses to this question covered a wide range, including the re-evaluation of Integrated Resource Planning (IRP) rules by the IURC, the continued use of the IRP rules with new requirements, to the changing nature and timeframe of resource planning. A few respondents believed that the twenty-year horizon was no longer relevant, and that ten years (or even five) was a better criterion. Also, due to the changes in the wholesale power market and the price uncertainties thereto, the planning process has evolved to incorporate such changes. Utilities are incorporating more risk management (including products such as options, forwards and futures) and probabilistic assessment into the decision making process, thus using planning techniques developed by the oil and natural gas industries.

Other respondents stated that with the maturing power market and the development of merchant plants and RTOs, long-term resource planning will continue to serve a useful business purpose if not a regulatory purpose. Two respondents, AEP and PSI Energy, questioned the continued need for the IURC IRP requirement in its present form. AEP stated that such rules might no longer serve a useful purpose in the future because NERC and RTOs will be planning for transmission grid integrity and reliability, and that state commissions may focus their attention on the planning requirements of the distribution and delivery system. PSI Energy recognized the need for the IURC and other parties to be informed of a utility's long-term plan, but believed that a more informal process might be a better way to accomplish the same goals. PSI Energy pointed out that the twenty-year planning horizon was probably too long, and that the details in the rules, while not individually burdensome, together require months of work for a utility to comply.

In opposition to the above arguments, the CAC believed that the IRP process is necessary and should be continued, and would like to see changes in the process. First, it wanted the review and approval of wholesale purchase power contracts to become part of the IRP process. Second, it argued that demand-side bidding should be incorporated into the IRP process.

5. What economic incentives or disincentives are present in Indiana's current regulatory process to provide for adequate and reliable long-term resource planning?

The Certificate of Need (CPCN) law was cited as a disincentive by PSI Energy and IPL. PSI stated that the CPCN law leads to lengthy, much-litigated proceedings, and that it does not exempt smaller distributed generation, combustion turbine, or small coal projects. IPL stated that it is a disincentive because it does not exempt shorter lead-time facilities such as gas turbines. NIPSCO and SIGECO cited uncertainty of future regulations regarding industry structure as a disincentive and SIGECO also cited the uncertainty of environmental rules and the recovery of wholesale purchased power costs as long-term planning problems. However, the OUCC took the other side of the latter issue by stating that there were possible disincentives for utility built generation or utility refurbishment or maintenance activities when the recovery of wholesale purchased power costs are allowed. The OUCC added that whether this is an actual disincentive depends on the method employed to recover wholesale purchased power costs.

Both AEP and INDIEC argued for the industry to become more market-oriented. AEP stated a basic belief in markets to provide for adequate and reliable long-term resource planning while INDIEC believes the current regulatory process hinders the development of a market-based system, and that a utility should not be subject to any more business and legal requirements than any other potential supplier.

The CAC cited three major disincentives: Uncertainty regarding the nature of merchant plant participation in new power plant certification; 2) uncertainty regarding the role of purchased (wholesale) power; 3) underemphasis in the process of demand-side resource acquisition by utilities. The CAC also stated that it did not want intermediate or baseload generating plants excluded from the CPCN process.

6. Should penalties be assessed for inadequate resource planning that places reliability at risk? How would this be determined and what type of penalties would be appropriate?

The utilities uniformly argued against the imposition of penalties. The general line of reasoning was that electric utilities are already obligated to provide reasonably adequate service, and if that standard is not met, there are existing remedies available to the IURC. Other problems with imposing penalties that the utilities cited included the problem of defining what "inadequate planning" is, and that judging it would inevitably involve some type of after-the-fact review which would be unfair to the utilities. NIPSCO and PSI Energy argued that incentives work better than penalties to influence behavior. In a restructured, competitive environment, IPL and AEP stated that the market would likely provide sufficient penalties to those that perform poorly.

The OUCC stated that any penalties should be implemented in a way that does not penalize good faith efforts by the utility to provide for its customers. The OUCC also stated that the judicious use of penalties would be useful in ensuring that utilities do the right thing in situations where the profit incentive does not fully coincide with the utility's responsibilities under the law. The CAC stated that any penalty imposed by the IURC would pale in comparison to the cost to society from poor or incomplete resource planning, so it argued that the key to the existence of a reasonable long-term planning process is for the IURC to pro-actively monitor and initiate investigations of utilities when indicated.

7. How can generation planning and adequacy be addressed on a regional level?

NIPSCO and the OUCC cited the State Utility Forecasting Group, which currently assesses generation planning and adequacy within Indiana. Several utilities and the OUCC stated that ECAR performs regional assessments of load and capacity for each summer and winter peak load season and an annual 10-year capacity margin study.

Several utilities also cited NERC and the formation of RTOs as other possible groups that may perform regional planning.

8. How has the occasional volatility of the wholesale market affected the planning and implementation strategies by the utilities for meeting customer demand? Conversely, how does the lack of a market-sensitive price signal to the retail customer affect the planning and implementation of strategies by the utilities for meeting customer demand?

Several utilities stated that the occasional wholesale market volatility has affected operational planning in that they must be more vigilant with respect to meeting the peak load. Many cited risk management strategies, particularly the use of hedging to ensure supply at a reasonable price. AEP cited proper maintenance of generating units in order to ensure maximum output during regional periods of short capacity.

The lack of price signals to retail consumers drew many comments. First, several utilities cited their pricing programs and tariffs for larger customers that do send price signals. Second, the consensus opinion was that it is absolutely necessary to create demand elasticity, and that even a small demand response to market pricing can have a significant effect on market volatility.

9. What are the implications of generation adequacy in the region and in Indiana of depending increasingly on the impact of the market-oriented policies to stimulate sufficient and timely generation investment?

Most parties believed that market-induced generation additions would be a positive development for Indiana and the region. PSI Energy stated that a traditionally regulated utility should not necessarily rely solely on capacity additions or power purchases for reliability, but the addition of more capacity to the region makes purchases, short lead time capacity construction and cost effective demand-side management (DSM) the three prime candidates for meeting demand today. AEP stated that non-regulated companies can more rapidly respond to market conditions, and that rather than utility customers bearing risk to install new capacity, third-party corporations and their shareholders will now bear a large part of these risks.

IPL stated that there may be boom and bust cycles in the generation market, and that price hedging will be important for utilities to employ. Further, IPL stated that if policy makers remove the ability and/or the incentive to hedge against these market price swings, a situation similar to California could develop, where all price volatility is passed through to consumers (refers to the San Diego area in the summer of 2000). IPL believes that some of their customers do not wish to be exposed to the price swings of the wholesale market, and would rather have their supplier manage the price volatility.

SIGECO pointed out that the sufficiency, reliability, availability and price of wholesale power have yet to be fully tested, and that the policies governing utilities and non-utility generation have yet to be fully developed.

10. How does availability and access to the transmission system affect utilities' strategies for meeting customer demand?

Parties acknowledged that access to the transmission system and the extent of transmission constraints limiting purchased power is certainly a major factor in determining whether to buy power or build capacity. The development of RTOs and inter-RTO agreements was hoped to enhance transmission reliability and expand the reach of markets in the future. Wabash Valley Power Association (WVPA) was very concerned that a lack of transmission system expansion coupled with more generating facilities could limit the flow of power during extreme load conditions, and thus limit WVPA's ability to select a least-cost power supply. WVPA remained very concerned about the lack of an integrated transmission plan for the Midwest region.

Summary of Session 5 Discussions:

This session began with an assessment of present and future generating reserves. The main topic was what type of information ECAR collected about new generating plants to incorporate into its forecasts. ECAR collects information from its utility and nonutility members as well as from nonmembers. Some of this information may be competitively sensitive. ECAR aggregates and analyzes the information and then disseminates it to the public and the members of ECAR. Several potential problems inherent in collecting the information were discussed, such as incorporating nonutility generation and restructuring activities across the states. The information that ECAR assimilates is as good or better than that of any other entity.

Attention turned next to the utilities' forecasting methods for supply and demand, and the various reliability criteria used, such as loss of load hours per year, probabilistic load profiles, and expected unserved energy.

The ECAR Automatic Reserve Sharing system was explained and discussed. In an emergency, a utility can call upon other members of ECAR to help with generation deficiencies for a short time. Initially, the immediate neighboring utilities are required to help. If that is not sufficient to solve the problem, a call for help will go out to the 2nd tier utilities.

The State Utility Forecasting Group gave a presentation explaining their forecasting methodology and the data requirements necessary to operate the model. This was followed by discussion of the state of long-term planning in the changing industry environment. One party noted that the nature of the new loads connecting to the grid is dictating the types of units—peaking and intermediate—that are being added in the region. Another participant noted that greater uncertainty increases the need for a long-term plan, and that the long-term plan should incorporate non-utility generation. In this environment, wholesale purchased power becomes more important, and the retail utility has an obligation to procure the commodity much like a local gas distribution company procures natural gas for its customers. With this change in the planning process, there will be a need for licensing or certification of generation suppliers, as well as an expedited process for non-utility generation filings and approvals, various parties asserted. Another party noted that the market approach to spur new generation was working well in the PJM (Pennsylvania-New Jersey-Maryland) RTO, where retail and wholesale competition has been enacted, there will be approximately 15,000 MW of generation added in the next two years.

Issues for Further IURC Consideration:

Changes in utility forecasting and planning are of primary concern to the commission. It appears that, to an increasing extent, utilities will be relying on the wholesale market (nonutility generation) for some needs. The IURC needs to continue to understand and monitor the changing nature of the utility's planning process. Also, the State Utility Forecasting Group, which creates a forecast for Indiana's needs as a whole, will need to incorporate the changing nature of resources being used by utilities.

The commission will need to keep a close watch on how well market forces are providing generation resources for Indiana utilities, and, indirectly, ratepayers. This is important because if there were a shortfall of resources, reliability could be compromised. Another potentially detrimental effect could be a significant rise in the price of wholesale power paid by Indiana utilities. If this were to occur, utilities and ratepayers could be harmed by paying higher prices for power, depending on how the higher prices were accounted for. If the situation were to significantly deteriorate, the commission would have to examine the possibility of ordering Indiana utilities to build their own generating plants.

Increased reliance on various types of wholesale purchases from different types of suppliers and with different degrees of "firmness" necessitates that both the utilities and the commission become more familiar with the concepts of risk management and resource portfolio theory. Recent experience in the electric and gas industries highlight the importance and difficulty of using these tools to the benefit of customers. The IURC should closely monitor how utilities incorporate these concepts into their long-term resource plans and how the methods are used in conjunction with wholesale purchases.

The IURC Staff created the following matrix as a way to help organize thoughts and think about electric forecasting:

+/- Of Forecasts Being Produced

	Forecast of Loads	Evaluation of Resources	Securing Resources
Utilities	+ Have the best access to information about their service territory, especially end-use information. - Forecasts limited to their service territory.	+ Best information on what type of resources would best fit their system. Insight on how various DSM programs would be accepted by customers. Can include transmission and distribution in the evaluation. - Cannot evaluate how various resource options may effect the regional system. May place too much dependence on making purchases from the wholesale market.	+ Have the financial resources and technical expertise to purchase and install or build necessary resources. - May be reluctant to invest in long-term resources due to the uncertainty in the utility industry. Have not select resources that benefit the region as a whole.
SUFG	+ Have reasonably good access to information through the IRP and of sources and develops statewide forecasts. Can somewhat take into account merchant plants. - Have less access to end-use information and “insider” type information about future changes. Limited to a state perspective.	+ Can make broad evaluations of various types of resources and can somewhat identify prime locations for new resources. - Little ability to determine which types of DSM resources would be best accepted by customers. Little/no ability to evaluation innovative technologies such as photovoltaics or DG or transmission facilities.	Not Applicable
ECAR	+ Aggregates forecasts from utilities on a regional basis. Can somewhat take into account merchant plants. - Dependent on utilities for information and forecasts.	- Resource evaluation limited to determining how much power may need to be imported into the region during peak periods.	Not Applicable
RTOs (since RTOs are in their infancy, these points may be somewhat more speculative)	+ May potentially do with either by developing its own models or by aggregating the forecasts of its member utilities. - Potentially produces forecasts with “holes” where utilities are not members. May not produce forecasts.		+ Could potentially dictate the implementation or construction of facilities by member utilities. - Regulatory conflicts and cost recovery.

Source: IURC Staff

Session 6:
Non-Utility Owned Generation
Meeting Date: October 30, 2000

Objective: The objective of this session was to examine the effects of non-utility owned generation on statewide and regional reliability. The Commission wanted to discuss the advantages and disadvantages of having non-utility owned generation built in Indiana. Also, the factors that influence the construction of non-utility owned generation (access to natural gas, access to transmission lines and the robustness of the wholesale market) were reviewed. Finally, the Commission wanted to address how non-utility owned generation should be viewed when assessing the generation capacity status of the state and region.

Written comments for session 6 were filed by: American Electric Power, Citizens Action Coalition, DeSoto Community Group, Duke Energy North America, Hoosier Energy, Indiana Industrial Energy Consumers, Inc., Indiana State AFL-CIO, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Office of the Utility Consumer Counselor, PSI Energy, Inc., Dr. Jim Rybarczyk, Southern Indiana Gas & Electric Company, Wabash Valley Power Association, and Williams Energy Marketing & Trading.

Summary of the Written Comments for Session 6:

1. What are the economic incentives and disincentives faced by Indiana utilities and other market participants when it comes to investing in generation and transmission facilities?

There was significant agreement among the different participants that generation and transmission investments will occur when the expected rate of return is adequate to compensate for the risk involved. Uncertainty associated with pricing, permitting or regulatory approval or delays could negatively affect the economics of a project and thereby the risk.

In addition, some participants suggested that the economic incentives for investment in merchant facilities, i.e. high risk can equal high profits, are providing a disincentive for investment in regulated plants and demand-side management programs. They noted a system-wide tendency in favor of merchant generation investment and power purchase agreements, rather than additional investor-owned utility (IOU) generation construction. Also mentioned were the disincentives to investments in transmission such as: increased siting difficulties, slower capital recovery, and lower rates of return. AEP cited a recent article from The Energy Daily, which stated that the rates of return for transmission projects have been in the range of 9%, whereas in a truly competitive market, the returns would have been in the range of 15-20%.

2. How does non-utility generation benefit the people of Indiana?

Most commonly mentioned benefits for Indiana citizens included: the economic development benefits of jobs, tax revenue, and other economic multipliers, the benefits associated with a diverse fuel supply, and those associated with the reduction of transmission congestion and increased ancillary services and system support.

3. The Midwest might need large amounts of peaking capacity over the next few years, but what happens if too much capacity is built? What is the possibility of cycles of boom and bust in the electric generation business? What does it mean for the level and volatility of prices in the wholesale market? How would such cycles, should they occur, impact reliability?

All participants agree that an extended period of tight markets and high prices will induce generation construction and due to the timing disparity of the supply and the subsequent prices signals that drive investment, boom and bust cycles will always be possible in this industry.

The market has experienced such cycles before, even under a regulated electricity market. A lack of generation in the 1970s was followed by a major build-up in the 1980's. Then there was an overabundance in the early-1990's and no further construction, which caused the significant needs of this period for additional peaking capacity. Similar trends have been witnessed in the gas market and prices at the wholesale level have acted and will act accordingly.

Utilities and marketers are not nearly as worried about the possibility of the boom and bust cycles in the industry as were the citizen participants. Most agree that the term 'bust' is an over dramatization of a temporary market imbalance and note that merchant facilities have more flexibility to change the levels of their output to meet market demands than a typical IOU as they don't have to produce if the market is not lucrative. Because of this flexibility, the utilities and marketers believe that instead of going bankrupt as the consumer groups fear, facilities will merely slow their production during times of oversupply.

Important to note in the answers to this question is the fact that all participants agree that a boom-bust cycle is probable in the industry. The only disagreements center on the extent of the 'bust' period and its potential for harming consumers and exactly when such a downturn in the market could occur.

4. Excluding requirements mandated by the Environmental Protection Agency and provisions made in power sales contracts, what requirements and/or obligations must a non-utility owned generator meet (e.g., FERC, NERC, ECAR)? Please explain.

Under the Federal Power Act (FPA), an exempt wholesale generator (EWG) is subject to the jurisdiction of the FERC, but is exempt from certain requirements of the FPA and FERC rules and regulations that otherwise apply to IOUs. To participate in the wholesale market, the EWG must also file a power marketer application with the FERC, which gives it the authority to charge market-based rates for its generation. An EWG must also report its wholesale power transactions with the FERC.

Once a non-utility owned generator applies for membership in ECAR, it has all the same obligations and requirements associated with membership.

5. The adequacy and availability of transmission in the near future may diminish as increasing load, generation and wholesale transactions, impose a greater burden on transmission-related facilities. Could this hamper the ability to add non-utility generation in a timely manner? Is this a real concern? What can be done to improve the coordination between transmission planning and the market-driven investment of generation facilities?

Siting generation closer to load and well-coordinated (and operational) RTOs seem to be the only solutions to this legitimate concern. IPL worries that new generators merely want to connect to a transmission system without long-term commitments to transmission system adequacy.

6. Can the interstate gas pipeline system deliver adequate supplies of natural gas to meet the need of traditional customers plus the increasing needs of new generation being built in Indiana and throughout the region? How will gas prices and electricity prices move relative to one another? What impact will seasons and weather conditions have on the interrelationship between gas and electricity prices?

According to IPL, there are currently six interstate pipelines that run through the State of Indiana. The daily pipeline deliverability into Indiana exceeds 10 billion cubic feet (bcf) per day. Existing gas-fired electric generating capacity in the State of Indiana could consume as much as approximately 2 bcf per day. Currently proposed additional gas-fired electric generating capacity could increase consumption from approximately 2 bcf per day to approximately 4.5 bcf per day. These consumption numbers assume that the plants run 24 hours per day at full capacity, which is an extreme assumption.

Gas consumption for the State of Indiana averages approximately 1.7 bcf per day for residential, commercial, industrial and electric generation using data from 1995 through May of 2000 ("Natural Gas Monthly" – EIA 0130). This average daily consumption peaks in the month of January at approximately 2.7 bcf per day. Given the 10 bcf of pipeline capacity available, it would appear on the surface that Indiana has ample pipeline capacity to meet current and future gas fired electric generating consumption. However, only about 30% of the existing pipeline capacity is actually utilized within the State of Indiana. The remaining 70% of the interstate pipeline's deliverability capability serves other states. Therefore, unless additional interstate pipelines are constructed to serve other states and Indiana, the supply of natural gas to serve all customers could become tight during certain winter and summer peak periods.

The relationship between gas prices and power prices varies by region in North America, and is a function of a few different factors. The relationship is strongest in those regions where gas-fired generating units are on the margin a significant portion of the time. In these regions -- such as California, Texas, and New England -- the gas price often determines the dispatch cost of the marginal unit and effectively sets a floor for the power price.

In regions where other fuel types like coal resources or nuclear units are on the margin primarily during off-peak times, changes in the gas price do not have a significant correlation with changes in the power prices. ECAR and MAIN[17] use gas-fired resources less often than other regions and only during the peak hours.

Weather conditions have a definite impact on the correlation between gas prices and power prices. The greatest correlations can be observed in the spring and fall when weather conditions are less extreme and the influence of gas prices as described above is not overwhelmed by extreme weather-related demand. In the summer, power prices can reach extreme levels if temperatures produce enough demand to strain the system. In the winter, very cold weather could produce spikes in both gas prices and power prices, however the relative increase in power prices is likely to be greater because of their volatility.

7. The location of merchant plants seems to be driven by the proximity to both the electric grid and gas pipelines rather than where it will do the most good for the electric system. Is there a reason to be concerned about this? Please explain. What needs to happen in order to make sure that merchant plant developers build these units in areas that will provide the most value for the electric system?

Merchant plant developers examine a number of factors, including proximity to the electric grid and gas pipelines, before selecting a site. Other factors examined include: the availability of adequate water supplies, air attainment status, zoning and tax incentives, and local support/opposition. Some argued that local opposition is a major factor in determining location of these facilities, meaning that perhaps they would locate closer to large load areas if it was not so difficult to build additional gas and transmission lines in highly populated areas. More likely is the assertion that these plants locate as close to gas and transmission lines as possible because it is more economically efficient for them to do so. The farther a generating unit is from the grid and a pipeline, the more their plant will cost to construct. The more expensive the plant was to construct, the more they will have to charge for their electricity to meet their financial obligations and the less competitive they will be on the wholesale market.

[17] The Mid-America Interconnected Network, which is the reliability organization to the west and north of ECAR.

According to some commentators, the Commission should examine the location of each plant on a case-by-case basis to have any influence over the type and site-selection of the future merchant plants in Indiana. By using the ability to approve and disapprove petitions on a variety of public interest issues, the IURC could choose to encourage the types of facilities that will most benefit the citizens of Indiana and the reliability of the system.

8. From a developer's perspective, what economic and/or financial criteria must be met for a merchant power plant project to begin? What criteria do financial institutions and/or investors use when evaluating merchant plant projects as investments?

Participants agreed that the criteria for proceeding with a power project varies by company, but the common metric used by all investors will be return on capital deployed as measured by Internal Rate of Return (IRR), Return on Equity (ROE), Earnings per Share Contribution (EPS), all adjusted for risk. These calculations are based primarily on the forward price curves of gas (and other fuels) and electricity, and the amount of capital necessary. The forward price curves determine the number of operating hours per year where the market price of electricity is above the cost of generation, fixed and variable, to substantiate the return on capital.

The financial institutions likely use the same basic approach; as the investors want to see the same result, return on their capital. Investors will review the forward price curves of fuel and electricity, the capital and operational costs, and any contracts for capacity that may have been entered into.

9. Are there federal, state or local regulations or requirements that encourage one type of generating unit over another whether by fuel type or operating patterns?

With respect to fuel type, there are no federal, state, or local regulations that explicitly favor one type of generation over another; however, environmental and safety regulations at the federal level are playing an increasing role in dictating energy policy and shifting the mix of generating capacity away from nuclear and coal-fired capacity and encouraging the use of natural gas for the generation of electric power.

Summary of Session 6 Discussion:

This was a well-attended session with a number of marketers present along with citizen representatives. The meeting kicked off with a discussion of potential affects of merchant plants on the transmission system. The transmission owning utilities present noted that via the transmission service agreements entered into by merchant plants, they have the authority to adjust the voltage, increase or decrease output or to disconnect completely any connecting merchant facility. There was general agreement that this was an adequate means to control reliability on the grid until a RTO is up and running which, all agreed, would solve transmission problems more efficiently. A potential benefit to the transmission system of merchant plant construction is an increase in the 'robustness' of the system, meaning additional generation capacity added to the system. The argument is: the more robust the system, the more quickly it can return service after a contingency. Most of the day was spent discussing transmission issues.

Another topic discussed was financing of merchant facilities. Duke Energy, a leading owner of merchant capacity stated that they use an in-house financing subsidiary to fund their merchant plant projects. PSEG, another leading merchant plant developer, stated that their projects are usually more highly leveraged because they have long-term contracts in place for their output.

Issues for Further IURC Consideration:

Most of the major policy issues discussed were those already reviewed by the Commission during the approval process of each merchant petition.

The Commission should closely examine any trend toward the use of natural gas as Indiana's primary fuel source. All participants mentioned that consumers benefit most from a variety of generation sources and fuel types. Too much new or replacement gas-fired generation will likely cause our electricity prices to fluctuate along with the highly volatile gas wholesale market.

Participants in this session agreed that a boom-bust cycle in the wholesale power market would always be an unintended consequence of the industry structure. How and if the Commission can have any affect on this feature of the wholesale power market is arguable.

Although transmission-owning utilities would retain some kind of control over merchant plant operations via their transmission service agreements, the Commission can and should take the reliability of the grid into consideration when examining potential merchant plant sites.

All present seemed to agree that merchant plants are subject to the Commission's authority. The disagreements occurred over the extent the Commission should exercise this jurisdiction.

Session 7:
Quality Service Issues

Meeting Date: November 20, 2000

Objective: The objective of this session was to examine how reliable electric service is to the end-use customer. This session discussed the very basic concepts of reliability; how often electric service is interrupted; how long the interruptions last and how responsive the utility is to customer questions and problems. Further, this session addressed the development of appropriate service quality standards and what will be required to implement and monitor service quality standards. Finally, this session addressed if different customers have different service quality needs and how the utility may be able to use that difference to maintain or enhance reliability for all its customers.

Written comments for Session 7 were submitted by American Electric Power, Citizens Action Coalition of Indiana, Indiana State AFL-CIO, Indianapolis Power & Light Company, Dr. James Rybarczyk, Northern Indiana Public Service Company, Office of Utility Consumer Counselor, PSI Energy Inc., and Southern Indiana Gas & Electric Company.

Summary of Written Comments for Session 7:

1. How reliable is electric service in Indiana? How do utilities measure electric service outages? What are the annual results of these measurements for the past ten years? Is there evidence, based on these measures, that reliability to the end-use customers has deteriorated?

Electric service in Indiana is very reliable, and there is no evidence that reliability to end-use customers has deteriorated in recent years. The Institute of Electrical and Electronic Engineers (IEEE) has defined twelve different measures in IEEE Trial Use Guide 1366 for measuring outages and outage duration. All Indiana utilities that responded to this session use two or three of these measures to track reliability. These are: Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI)[18]. One other utility uses two other measures as well, the Momentary Average Interruption Frequency Index (MAIFI) and the Average Service Availability Index (ASAI)[19].

[18] CAIDI is an indicator of outage response time, and is determined by calculating the average interruption duration or average time to restore service for a specified time period per interrupted customer.
SAIFI is an indicator of the frequency of outages to the average customer, and is determined by calculating the average number of interruptions for a specified time period per customer.
SAIDI represents the average interruption duration on a system-wide basis.

[19] MAIFI tracks the frequency of momentary interruptions.
ASAI measures the percentage of time during the year that an average customer is provided with power.

It should be noted that comparing numbers across years or across utilities can be problematic, because utilities may have different thresholds for reporting outages (such as 2, 5, or 10 minutes), may have different methods of collecting outage data (manually or automated), and have changed the data collecting method through the years, and the indices are heavily influenced by weather activity. A further factor in examining the indices over time is that as manual reporting systems are replaced with automated procedures, the indices may increase due to more events being counted even though actual reliability stays the same or even improves.

One utility noted that it believed its reliability had steadily improved over the last few years due to capital investments in the infrastructure in key areas and in new technology installed in substation maintenance, distribution system automation, infrared thermography, protective relaying, and storm restoration.

Among various consumer advocates, there was some concern of the potential for reliability to decrease in the future. Reasons cited for these concerns included a lowering of labor, equipment, and maintenance efforts at the utilities, the destabilizing effects of restructuring or deregulation regionally and nationally, the belief that the experience some consumers had with a local telephone company could occur in the electric industry, the effects of mergers, structural reorganizations, staffing reductions, and induced retirements of experienced personnel. Since this issue was not directly included in the question, there were no utility responses to it.

2. Which of the measures cited above are appropriate and useful indicators or measurements of reliability at the generation, transmission and distribution levels? Are there other measures that should be used or added to those mentioned in Question 1?

Most parties recognized that although the IEEE measures cited above can sometimes be affected by generation and transmission problems, in the main they are measures of distribution reliability. Measures of generation reliability are the availability factor[20] and the forced outage rate[21], but small variations in such measures are basically imperceptible to end-use consumers. This is because if a generation unit or transmission line fails, the electric system as a whole automatically adjusts (by increasing other generation or electricity flowing over other transmission lines) for the problem and electricity continues to flow except to the locally affected area. This adjustment mechanism is the main reason why local systems across the nation are interconnected with each other.

3. Would it be useful to develop standard measures for electric service quality? What should those measures be and how should the standards be set?

[20] Availability factor is the fraction of time a generating unit is able to supply power at various capacity levels.

[21] Forced outage rate is the rate at which a generating unit is shutdown for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

The utilities generally were not in favor of having the IURC develop standard measures for electric service quality. They argued that the IEEE measures are already standardized, and the important factor is for each utility to use consistent measures through time for its own company. Implementing one standard for all utilities is problematic or even impractical because of the unique characteristics of each service territory (such as the type of area served, customer demographics, and utility design). One utility noted that additional measures for electric supply quality are under development by the IEEE, but the effort showed that standard measures are highly technical, difficult to implement, and fail to account for the complex interaction between customer loads and the electric supply system. Another utility offered that if a single measure were to be employed, it would recommend the Customer Service Reliability Index (CSRI), which is a combination of SAIFI and CAIDI.

The AFL-CIO, the CAC, and the OUCC all believed that it would be useful for the IURC to develop standards for electric service quality. The CAC stated that these standards would assure that service quality is measured in a consistent and systematic way and provide a basis for assuring that appropriate levels of service quality are maintained as the structure of the electric utility industry and the role of competitive markets in defining, pricing, and delivering electric service evolve. The CAC believes that such standards should be set by IURC rule after a formal rulemaking, and that the standards should be set at levels which meet customer expectations for reliability. The OUCC noted that such standards would need to accommodate unique conditions, such as the number of customers per mile of line or unique weather events to account for differences among utilities.

4. What factors affect electric service quality (i.e. adequate generation, transmission and distribution facilities, supply resources, maintenance schedules and strategies, tree trimming, staffing levels, communication with customers)? Which of these factors are more fully under the control of the individual utility and which are more regional in character therefore less controllable by any one utility?

All of the factors listed in the question affect service quality, but history has shown that adverse weather activity is the largest single factor affecting reliability. Of course, this is not under control of the utilities. The second leading cause of distribution outages is trees. This is under some control of the utilities, but tree trimming must be balanced with the aesthetic considerations of customers. Also, trees next to overhead lines can grow quite large and then fall into facilities due to ice or rainstorms. Other factors in outages are animals, dust, air quality, corrosion, and proximity to highways or industrial processes, component failures. These can be mitigated by system design, operation or maintenance procedures. Two other important factors in how a utility manages outages are staffing levels and communication with customers. Regional issues include the growth of non-utility generators and their need to interconnect with the transmission system, and the FERC mandate for utilities to join Regional Transmission Organizations (RTOs). Finally, the siting of transmission facilities can be a concern since the process can take many years or even decades.

5. Should penalties be assessed for not meeting service quality standards? What would be appropriate penalties and how should they be applied?

The utilities responses to this question were essentially the same across the board. First, a general answer of "No", penalties should not be assessed for not meeting service quality standards. This response refers to additional penalties assessed for any possible new service quality standards implemented by the IURC. The basic reasoning for this response is that electric utilities already have an obligation to provide reasonably adequate service (under IC 8-1-2-4), and an electric utility's exclusive right to provide retail service is defined as continuing to "provide adequate reasonable service" under IC 8-1-2.3-4.

The utilities further pointed to the ability the IURC has to investigate allegations of inadequate, insufficient or unsafe services or practices and to order the utility to correct the situation (IC 8-1-2-69). They argued that penalties should only be contemplated in cases of willful failure to discharge this responsibility, and that the ultimate sanction would be the loss of the exclusive right to serve.

The AFL-CIO stated that the IURC must have fining authority, and the OUCC stated that the IURC should have the ability to penalize, and that the penalties should be large enough to focus utilities' management practices and investments so that as much attention is paid to customer service as is given to profit making. The OUCC cited the experience in the telephone industry as evidence that such authority for the IURC is needed.

6. There is evidence, for example interruptible customers, that some customers would accept a lower level of electric reliability in return for lower cost power, how can the utility capitalize on this to maintain or enhance reliability to its customers as a whole?

Responses detailed the many current and some potential interruptible programs that utilities are now conducting or may conduct in the future. But, as pointed out by AEP and others, reliability should be viewed separately as generation supply and deliverability functions. Interruptible programs target supply reliability by helping to keep the proper level of generation reserves in times of tight supply. For the delivery function, a reliability problem occurs when there is an unexpected disruption in service. However, if different customers have different preferences for the level of delivery reliability they are willing to pay, there is no practical means for the utility to maintain different reliability levels for such customers. Except for differences in local characteristics, the distribution system as a whole will have one level of reliability, and it cannot be graduated based on customer preferences.

Summary of Session 7 Discussions:

The session began with a general discussion of the reliability indicators and general agreement that SAIFI and CAIDI were the best ones to use. The problems with comparing these between utilities were pointed out as they were in the written comments. Problems with using the indices for one utility over time were pointed out as well. These included the possible inconsistency of historical data due to field personnel making subjective judgments about what to include, customers who are out may not be counted consistently, and that some utilities may have switched from manual to an automated reporting system. A detailed discussion about how each of the utilities account for storms and the extent of weather normalization in their data ensued.

The next part of the session had the utilities explaining the types and frequencies of the customer satisfaction surveys that they perform. This was followed by details of the methods of how utilities count outages. The rest of the day included discussions about call center coordination issues; distribution budgets; how to evaluate performance and the use of internal targets; equipment failure and replacement; balancing the cost of reliability; trends for the future and power quality issues; labor issues (training, safety, licensing, pay); and the IURC ability to penalize for service quality issues.

Issues for Further IURC Consideration:

The main issue for commission consideration here is whether the IURC should embark on a process to establish service quality rules for providers of electricity. The benefits of establishing such rules are that consistent measures would exist for all utilities, and the commission would have a better way of comparing utilities performance with each other as well as over time. On the other side of the argument is the question of whether new rules are necessary or would even be useful to the commission. Utilities currently calculate a few to several well-known service quality measures, which can be used to compare performance over time. Some would argue that due to differences in territories, etc., that comparing measures across utilities is problematic at best. It could also be argued that the commission already has enough tools at its disposal to make sure that service quality is maintained. The commission can use its own database of complaint calls as a first indicator that a utility is experiencing service quality problems. The commission can also initiate investigations of utilities, and can invoke penalties if necessary.

Nevertheless, staff recommends that the commission initiate a rulemaking process to develop service quality rules and criteria. All electric utilities are evolving with increasing speed as the market and regulatory environment in which they operate changes. Electric utility companies are cutting staff resources and their holding companies are devoting ever increasing attention and resources to unregulated activities. The possibility of more utility mergers in the future can only accentuate these changes while further diverting attention from basic utility functions. A rulemaking will enable the commission to be both better informed and to create a process to take corrective action in a timely manner if the need arises.

1. LIST OF ACRONYMS

AEP…………….American Electric Power Company
ARS…………….Automatic Reserve Sharing
ASAI…………... Average Service Availability Index
CAAA………….Clean Air Act Amendments
CAC................ Citizens Action Coalition
CAIDI………….Customer Average Interruption Duration Index
CPCN…………..Certificate of Public Convenience and Necessity
DG………………Distributed Generation
DOE .... Department of Energy
DSM................ Demand-Side Management
EIA……………..Energy Information Administration
ECAR .... East Central Area Reliability Council
EPA…………….Environmental Protection Agency
EPS……………..Earnings Per Share
EUE…………….Expected Unserved Energy
EWG……………Exempt Wholesale Generator
FERC .... Federal Energy Regulatory Commission
FPA…………….Federal Power Act
IDEM…………..Indiana Department of Environmental Management
IEEE……………Institute of Electrical and Electronic Engineers
INDIEC………..Indiana Industrial Energy Consumers
IOU .... Investor-owned Utility
IPL .... Indianapolis Power and Light
IRP .... Integrated Resource Plan
IRR……………..Internal Rate of Return
ISO .... Independent System Operator
IURC .... Indiana Utility Regulatory Commission
KWh .... Kilowatt Hour
LOLP…………..Loss-of-Load Probability
MAIFI………….Momentary Average Interruption Frequency Index
MAIN…………..Mid-America Interconnected Network
MISO .... Midwest Independent System Operator
NERC .... North American Electric Reliability Council
NIPSCO .... Northern Indiana Public Service Company
NOX……………Nitrogen Oxides
NRDC………….Natural Resources Defense Council
O&M…………..Operations and Maintenance
OUCC .... Office of Utility Consumer Counselor
PSI .... PSI Energy

PUC……………..Public Utility Commission
PUHCA .... Public Utility Holding Company Act 1935
PURPA .... Public Utility Regulatory Policies Act 1978
PX .... Power Exchange
REMC .... Rural Electric Membership Cooperative
ROE……………..Return on Equity
RTO .... Regional Transmission Organization
SAIDI…………..System Average Interruption Duration Index
SAIFI…………..System Average Interruption Frequency Index
SCR……………..Selective Catalytic Reduction
SEC .... Securities and Exchange Commission
SIGECO .... Southern Indiana Gas & Electric Company
SNCR…………..Selective Non-Catalytic Reduction
SUFG…………..State Utility Forecasting Group
T&D .... Transmission and Distribution
TLR……………..Transmission Loading Relief
WVPA .... Wabash Valley Power Association

2. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity Margin: The percentage difference between rated capacity of a generation fleet and peak load divided by rated capacity.

Call Option: A call option contract allows the utility to call upon a specified amount of power or load from a customer when the wholesale price reaches a certain price (the strike price).

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Certificate of Public Convenience and Necessity (CPCN): A permit issued by the IURC that allows a utility to construct facilities, engage in business, or perform some other service. (IC 8-1-8.5)

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Green Power: Term used to describe electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Interruptible Rate: An interruptible rate is a lower rate offered by a utility to a customer that allows the utility to interrupt electric service.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Megawatt (MW): One thousand kilowatts or one million watts.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America, including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Power Exchange: An independent entity with no affiliate or financial interest in distribution, transmission or generation companies or facilities. It would match bids submitted by utilities, power marketers, brokers and other participants ranking the bids on a least-cost basis and arrange for the power to be delivered.

Power Marketers: A business entity engaged in buying and selling electricity, but does not own generation or transmission facilities. Power marketers take ownership of the electricity and offer risk management derivative products such as options, swaps, forward contracts and electricity futures.

Public Utility Holding Company Act of 1935 (PUHCA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state or presumed to be susceptible to effective state regulation are "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Real Time Pricing: Real-Time Pricing is the instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Renewables Portfolio Standard (RPS): A policy that obligates each retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources.

Reserve Margin: The percentage difference between rated capacity of a generation fleet and peak load divided by peak load.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Third Party Administrator: an independent entity that is funded through a public benefits charge levied on customers and oversees the specific conservation and renewable programs that are implemented.

Time-Of-Use Rates: The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on peak, mid peak, off peak and sometimes super off peak), and by seasons of the year (summer and winter).

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Transmission Loading Relief (TLR): A NERC procedure used to mitigate potential or actual violations of the operating limits on critical transmission equipment. These procedures are an escalating series of actions to reduce the electrical flow across key portions of the transmission grid.